# Canadian Wind Energy Association and Clean Energy Association of British Columbia Joint Comments on Commission Alternative Portfolios

## Introduction

The Commission has requested comment on three Alternative Portfolios and the assumptions that underlie these portfolios. The Canadian Wind Energy Association (CanWEA) and Clean Energy Association of British Columbia (CEABC) respectfully submits the following comments on these Alternative Portfolios and critical underlying assumptions.

First of all, it has been suggested by BC Hydro that what truly matters are the differences between the portfolios over the 70-year Site C analysis period. CanWEA and CEABC disagree. If as the Commission has proposed, DSM resources can be advanced and used to defer or potentially avoid higher cost resources this is an important benefit, which will be reflected in lower net present values for the portfolios. Furthermore, under risk analysis deferring or avoiding a major multi-billion dollar capital investment (such as Site C) can allow the decisionmaker to acquire additional information that would result in a different (e.g., lower cost, lower risk) investment decision as additional information becomes available (e.g., low electricity loads or cost reductions for alternative resources are realized). Such a benefit isn't obvious in the deterministic analysis that BC Hydro presents where it compares the aggregate resource additions of two portfolios.

## Hydroelectric Additions or Repowering

BC Hydro argues that Revelstoke 6 (Revelstoke) cannot be considered as an alternative to Site C because it is needed with or without Site C. We don't agree. More aggressive cost-effective DSM implementation and development of Site C could avoid the need for Revelstoke or at a minimum significantly delay the need for Revelstoke. This is significant because it pits the economics of Site C against those of Revelstoke and Revelstoke is significantly more attractive. BC Hydro's most pressing need is for capacity. Revelstoke represents 488 MW at a Unit Capacity Cost of $46/kW-year. Surprisingly, BC Hydro doesn't have Revelstoke enter commercial operation before Site C. We believe that this is because doing so would undercut Site C's economics. Clearly, electing to develop a higher cost resource before a lower cost resource is financially imprudent. Therefore, we believe that the Commission should include Revelstoke 6 as an element of the Alternative Portfolios.

While BC Hydro may argue that with a reputed UEC of $34/MWh Site C is more economic than Revelstoke 6, clearly Site C is dramatically riskier than Revelstoke 6.[1] The question becomes: "Is it appropriate to continue to pursue Site C at its reported cost given its significant risk profile or pursue the construction of Revelstoke 6, which is relatively low risk and better meets BC's overall requirements for additional capacity?". As discussed above, such an investment sequence would better allow BC Hydro to assess whether in fact Site C is less costly than alternatives because additional information regarding the cost of these alternatives will then become available. Such an approach is preferable from a risk

[1] CEABC has discussed elsewhere why the $34/MWh UEC offered by BC Hydro is not the project's true cost.

mitigation perspective because it would allow BC Hydro to obtain additional information regarding highly uncertain increases in electricity demand associated with proposed LNG projects.

BC Hydro also identifies possible refurbishments for a number of hydroelectric projects. Some of the most cost-effective options are identified in the table below along with their Unit Capacity Cost and Unit Energy Cost. We believe that these should be included as an element of the Alternative Portfolios given their attractive pricing and the logic outlined above.

**BC Hydro Hydroelectric Unit Refurbishments**

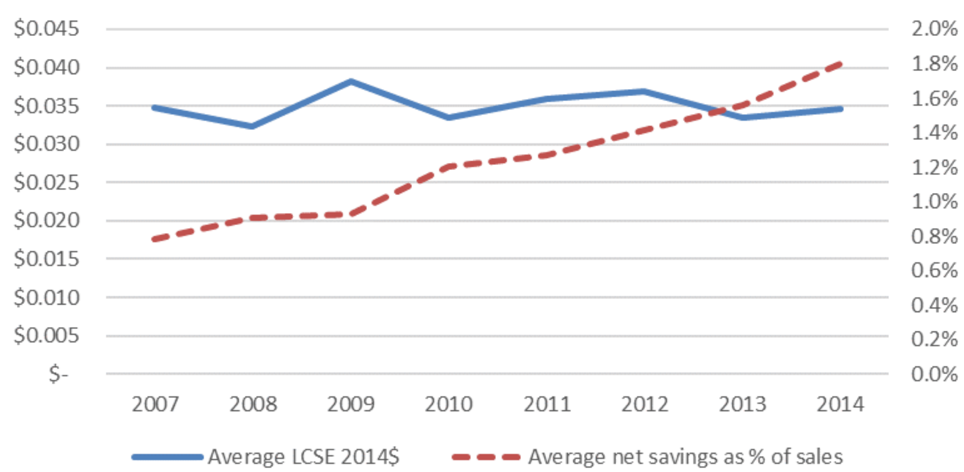
| Hydro Unit(s) | MW | GWh | UCC 2018$ | UEC |
|---|---|---|---|---|
| GMS Units 1-5 | 100 | N/A | $66 | N/A |
| Allouette Development | 21 | 61 | $21 | $51 |
| Punteledge Unit Addition | 10 | 18 | $126 | $69 |

Source: F1-1 submission, Appendix L, p. 44-48.

**DSM Impacts**

The Commission has included additional savings from cost-effective DSM programs as part of the Alternative Portfolios. This is appropriate and reasonable. BC Hydro assumptions regarding DSM impacts are well below those achieved elsewhere. The American Council for an Energy Efficient Economy (ACEEE) has determined that the leading energy efficiency service providers (i.e., 14 different energy efficiency program administrators) are able to produce energy savings of about 1.8% of retail sales, with the top four producing savings of greater than 2%.[2] Importantly, these savings were realized at a cost of about US$35/MWh and that this cost has not changed appreciably in the seven years that were evaluated in the study. See Figure below.

**Average Cost of Saved Energy and Energy Savings as a % of Retail Sales for Major Utility Programs**




Source: ACEEE, Big Savers, 2016.
http://aceee.org/research-report/u1601

[2] ACEEE, Big Savers: Experiences and Recent History of Program Administrators Achieving High Levels of Electric Savings, April 2016, p. iv.

To put BC Hydro DSM impacts in context, its May 2016 Mid Load Forecast for total requirements before DSM reflects a 2.6% compound annual growth rate (CAGR) from F2018 to F2024 and a 1.8% CAGR from F2018 to F2036. With the impacts of DSM programs considered, the Mid Load Forecast reflects a 1.8% CAGR from F2018 to F2024 and 1.4% CAGR from F2018 to F2036. As such, the net reduction in energy requirements from these DSM programs are about 0.8% through 2024 and 0.4% through 2036. Recall that the ACEEE assessment of leading energy efficiency programs indicated average savings of about 1.8% per year, over twice the level reflected by BC Hydro through 2024.

How reasonable are the additional DSM impacts considered as part of the Alternative Portfolios proposed by the Commission? The net effect of these assumed cost-effective DSM investments is a 1.2% reduction in energy requirements through 2024, which is still only two-thirds the level realized by leading DSM service providers, and a .6% reduction in energy requirements through 2036, which is one-third this level. This clearly suggests that additional increases in DSM investments beyond what has been assumed by the Commission in constructing its Alternative Portfolios is appropriate and reasonable.

One additional comment with respect to the Commission's assumptions regarding DSM impacts. The Commission has shown the same level of impacts under all three load forecasts that were evaluated. We would expect that under lower realized energy and peak demand growth that BC Hydro would scale back its programs and that this would eventually result in lower levels of DSM investment at lower realized electricity demand growth rates. This will result in lower exports in the Low Load Forecast Portfolio than reflected in Low Load Forecast Portfolio proposed by the Commission. The current assumption of consistent impacts across all three portfolios effectively penalizes DSM investments in the Low Load Forecast Portfolio given that the value of exports is lower than the DSM program costs. Investments in DSM, unlike Site C, can be modified to respond to load growth and by so doing better balance resources and requirements.

**Demand Response**

Consistent with our comments regarding the magnitude of the DSM energy savings presented above, CanWEA believes that more ambitious cost-effective peak load reductions can be realized by BC Hydro than assumed in the Commission's Medium and High Load Forecast Portfolios.

CanWEA and CEABC are concerned that BC Hydro is effectively calling into question the effectiveness of demand reduction programs by indicating that it requires "capacity resources that are available in aggregate to generate or curtail load for 16-hours per day for up to 36 days."[3]

We believe that a sixteen-hour duration for load curtailment is unreasonable. We reviewed requirements for other industrial demand response programs in the Pacific Northwest and were unable to find any similar requirements. Puget Sound Energy's Voluntary Load Curtailment Rider requires a minimum of a one-hour reduction.[4] Portland General Electric Company's Firm Load Reduction Program

[3] BC Hydro response to BCUC IR 3.19.0, p. 1
[4] https://pse.com/aboutpse/Rates/Documents/elec_sch_093.pdf

requires a minimum 4-hour duration for large customers.[5] Idaho Power's Flex Peak program for large industrial and commercial customers limits its event durations to two – four hours.[6]

A primary driver for the duration of peak load reductions is the typical peak day load shape. A review of a typical peak day load shape for BC Hydro indicates that 16 hours is well beyond what would be required to reduce the peak by amounts that BC Hydro is likely to able to realize. More importantly, it is well beyond what the vast majority of customers are likely to be able to offer or end-uses are able to provide.

If longer duration customer load reductions are required (e.g., 8 to 10 hours) these can be realized by BC Hydro by calling upon successive groups of customers to realize these load reductions. This is common practice elsewhere. In essence, BC Hydro would have a portfolio of demand reduction resources that it can call upon to manage its peak. This may affect the value offered to customers to participate, but if this value considers the cost of resources that BC Hydro has identified as required to provide capacity (e.g., pumped storage hydro), it is likely to be more than enough to induce high levels of customer participation.

**Batteries**

The inclusion of batteries in the Commission's Alternative Portfolios is reasonable and appropriate. Contrary to BC Hydro's assertion there's considerable experience with the deployment of batteries for utility applications. As discussed in our August 30th filing, California relied on batteries to provide 70 MW of required peaking capacity to replace a portion of the natural gas-fired generation that was unavailable when the Aliso Canyon gas storage facility was shut down last year. These batteries were deployed within 9 months, demonstrating their value as a contingency resource to address unanticipated risks. Furthermore, the PJM (Pennsylvania-Maryland-New Jersey) market has about 250 MW of batteries participating in its competitive electricity market.

**Wind**

The Commission appropriately relied upon the US National Renewable Energy Laboratory's *2017 Annual Technology Baseline* for its capital cost estimates for onshore wind. This is a highly credible and definitive source. However, the *2017 Annual Technology Baseline* relied upon NREL's *2015 Wind Technologies Market Report* as the starting point for its capital cost estimates. As indicated in CanWEA and Power Advisory's August 30th submission the subsequent *2016 Wind Technologies Market Report* reflected a 5.9% decline relative to the installed costs reported in the 2015 report. This suggests that there may be additional reductions in installed costs that have not been fully reflected by the wind capital cost estimates used by the Commission. This runs counter to BC Hydro's claims that the wind cost estimates are too optimistic.

CanWEA and CEABC believe that the proposed wind integration charge, which is effectively half that proposed by BC Hydro is reasonable and reflects the relatively limited penetration of wind in BC to date

[5] https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_077.pdf
[6] https://www.idahopower.com/pdfs/EnergyEfficiency/flexPeak/programBrochure.pdf

and projected future volumes and the ability of BC Hydro's existing hydroelectric resources to integrate additional volumes of wind cost-effectively.